Locational Net Benefit and Demonstration B Workshop 2/1/16

California IOUs' Approach

Objectives

1. Examine in detail utility proposals for:
   a. Locational Net Benefits Methodology (LNBM); and
   b. Demonstration project B
2. Explain how Locational Net Benefits Analysis (LNBA) can be used per DRP Proceeding's Scoping Memo Track 1: Methodological Issues

Common Definitions

A. **DRP Locational Net Benefit Methodologies:** (LNBM) location-specific values of DER benefits (but not net of DER deployment cost), to determine potential optimal DER locations.

B. **Potential Optimal Locations:** locations that combine high integration capacity with high DER benefits, such as feasible deferral opportunity, as determined through location-specific benefit values. Information about potential optimal locations will be provided publicly (e.g. integration capacity, deferral opportunity locations, requirements, other relevant info).

C. **Competitive Sourcing:** Process by which DERs/DER portfolios will be solicited and selected to provide services at potential optimal locations. Relevant benefits of each bid will be valued and ranked during the selection process.

D. **Locational Net Benefit Analysis**: analysis of location-specific DER benefits *and DER deployment costs*.

E. **Optimal Locations:** Locations where specific DERs/DER portfolios provide a net benefit to utility customers, as determined through ICA, DRP LNBM and competitive sourcing

Distribution Resources Planning Vision

Assumptions & Scenarios → **Distribution Planning Assessment** → **Feasibility Screening for DER Deferral** + **Determine Requirements** → **Potential Optimal Locations and Requirements** → **Competitive Sourcing for DER Deferrals**

Assumptions & Scenarios

Develop forecasts (demand/DER/generation), assumptions and planning scenarios

Distribution Planning Assessment

Determine locational distribution needs and associated traditional "wires" solutions.

Feasibility Screening for DER Deferral + Determine Requirements

Identify feasible DER alternative locations and associated requirements

Quantify range of locational deferral benefit

(For locations infeasible for DER alternative, implement original project)

Potential Optimal Locations and Requirements

Publish information on 1) hosting capacity, 2) feasible DER distribution deferral locations, 3) requirements, 4) additional relevant information

Competitive Sourcing for DER Deferrals

Use competitive sourcing to procure cost effective DER solutions in optimal locations based on location specific values of costs and benefits

Assumptions and Scenarios

Develop forecasts for DER and Demand

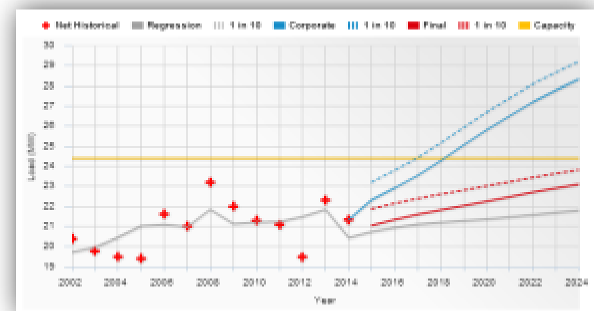
- DER forecasts from growth scenarios
- Demand and DER forecasts adapted from IEPR
- Demand forecast built on customer shapes by circuit and substation
- Planned utility projects of the system

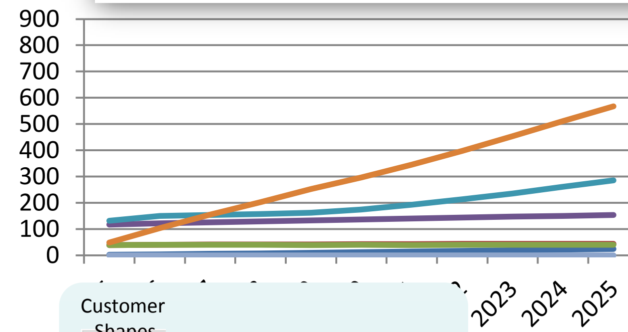
DER forecast assumptions

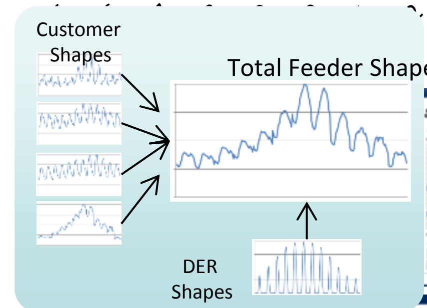
- Solar PV pro forma based on local irradiance
- Storage and EV respond to TOU signals

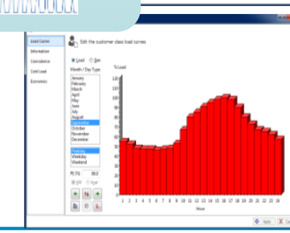
Timeline

- Planning Process is performed on a yearly basis
- Needs are refreshed based on its expected timeline
  - Near Term: 1-3 Years (i.e. primary distribution lines, voltage)
  - Mid Term: 3-5 Years (i.e. new feeders and substation transformers)
  - Long Term: 5-10 Years (i.e. new substations)







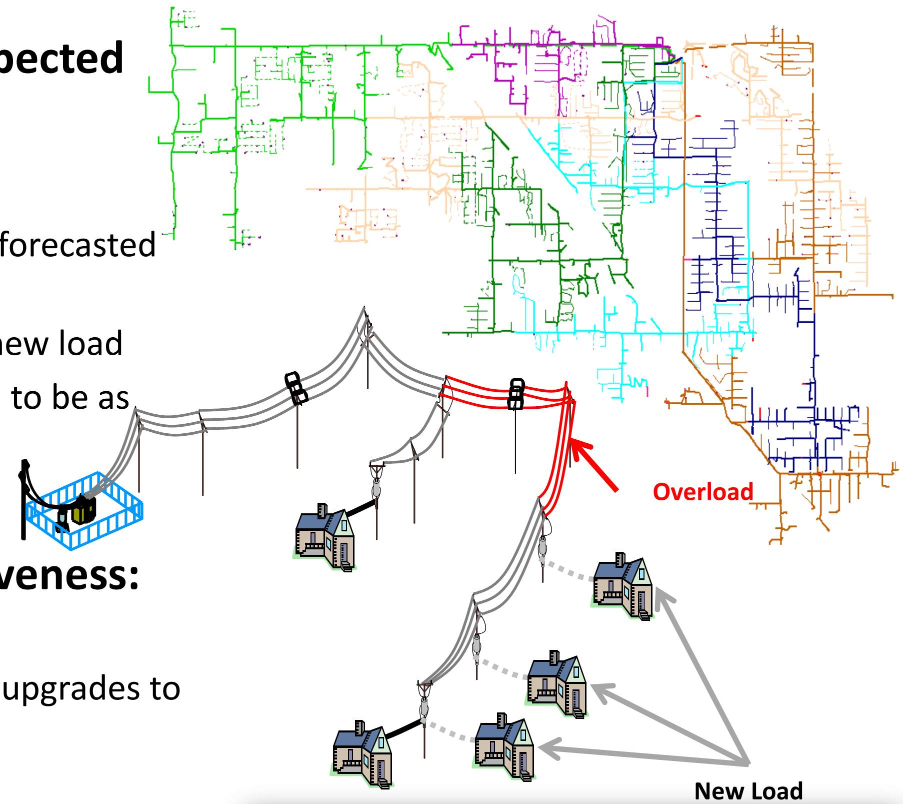


Distribution Planning assessment

Simulate power flow on circuit models with expected forecast

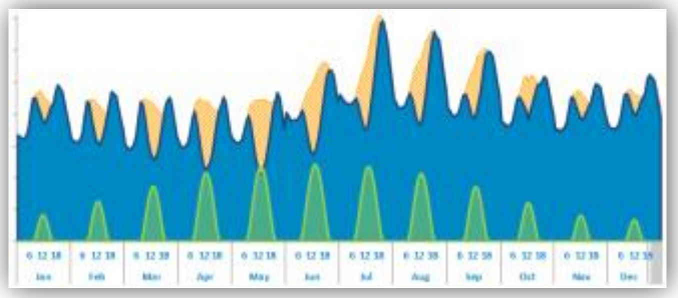
Determine Needs:

- **Capacity**: Thermal ratings of equipment are adequate for forecasted throughput
- **Voltage**: Customer voltage stays within Rule 2 limits with new load
- **Reliability**: Customer outage time and frequency is limited to be as short as possible



Possible Options, Alternatives, and Cost Effectiveness:

- **Transfers:** Utilize existing capacity, where available
- **Incremental Upgrades:** Identify smaller low cost system upgrades to enable use of existing capacity
- **Demand Reduction:** Identify DER availability
- **New Capacity:** Determine if a new asset is needed for new distribution



The main goal is to select the "least cost option" based on system conditions and available resources/options

- (i.e. demand reduction vs. upgrading capacity vs. DER solution)

Feasibility Screening for DER Deferral

- **<u>Objective:</u>**
  - Determine which conventional infrastructure projects can or cannot be deferred by DERs.
- **<u>Vision</u>**:
  - Develop clear set of technology neutral screening criteria and upfront standards
    - Collaborative stakeholder process to develop screens
    - Screens should evolve over time based on experience, technology advancement and grid capabilities
  - Collaboratively developed screens enable IOUs to make streamlined DER feasibility determinations
  - A systematic approach is needed due to diversity of systems, circuits, and load shapes across the IOUs' territories

Determine Requirements: Identify DER Characteristics Based on Grid Needs

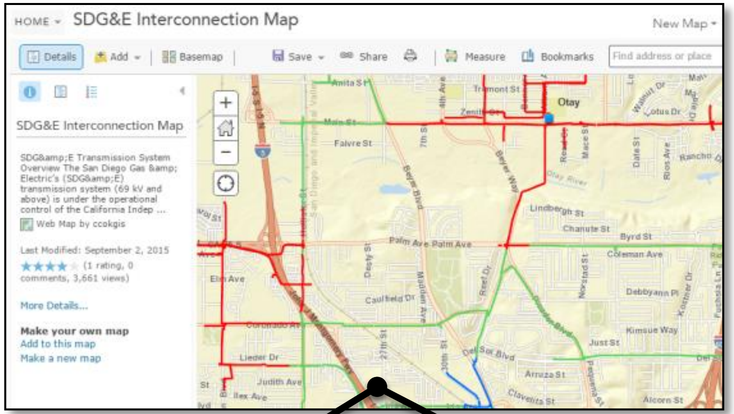
- For projects where DER deferral is potentially feasible:
  - **Identify locations and required capabilities**:
    - Service required: energy (or load reduction) and/or volt/var support
    - Magnitude/quantity of service
    - Timing for deployment
    - Specific operational requirements for frequency, duration, timing (e.g. "4 hour duration, every weekday evening, summer season")
    - Any other performance requirements
    - Control / dispatchability requirements

- For projects where DER deferral is not feasible:
  - **Implement conventional alternative**

Connecting the Dots:
Potential Optimal Locations and Requirements

IOUs provide information (data, maps, etc.) to help DER providers connect the dots and identify potential optimal locations

- Integration Capacity Maps
- Deferral Opportunity Locations
- Additional Details, e.g.
  - –Local capacity areas
  - –Historical, public market price information
  - –Appropriate additional information



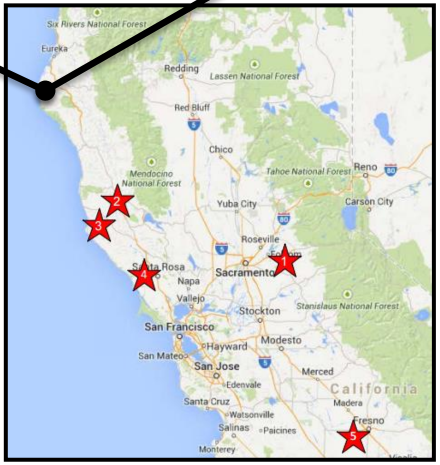
Deferral opportunity locations include technical requirements

- Size
- Timeline
- Duration
- Cycling
- Control
- Etc.

Distribution Deferral Project Requirements

Distribution Substation*	Guaranteed Dmax (MW) at Year 1-10	Guaranteed Discharge Duration (hours)	Guaranteed Site Specific Required Duty Cycle	Guaranteed Commercial Operation Date (later of)
Shingle Springs – Bank #2 Cameron Park, CA 95682	4	4	1/day for up to 365 days/year	May 1, 2017, or 12 months after CPUC approval
Mendocino – Bank #2 Redwood Valley, CA 94570	1	2	1/day for up to 365 days/year	May 1, 2018, or 12 months after CPUC approval

Additional Details



DER providers are given the right signals in the right locations

Competitive DER Sourcing

A competitive process is key to true optimal locations

- Competitive process ensures maximum value for utility customers

Specific services will be sourced by the utilities, not technologies

- Type of sourcing mechanism may vary across locations and time
- Specific products and services procured may vary
- Behind the meter and front of meter solutions considered

Solutions are evaluated using location-specific valuation

- Comprehensive evaluation requires a specific DER solution and associated cost
- Considers both quantitative and qualitative factors (e.g. DBE)
- Subject to appropriate external review

Selection of final solution based on highest net benefit solution

Pacific Gas and Electric Company®

Participant Information

Attachment A: Offer Form

Unless otherwise provided herein, all capitalized terms shall have the meaning ascri

Bidder Information

Bidder Name:

Street Address

City State

Authorized Contact #1

First Name

Last Name

Title

Phone 1

Phone 2

Email

Scheduling Coordinator Information

Scheduling Coordinator Name:

Street Address

City State

SC ID:

Supplier Diversity Information

Is your company a Diverse Business Enterprise (i.e., Woman-, Minority-, Service Disabl

Acknowledgement of Protocol

By selecting "Yes" participant hereby agrees to the terms of the Solicitation Protocol. costs incurred to prepare an offer for this RFO are solely the responsibility of Participa

Optimal locations: locations where DERs/DER portfolios provide a net benefit to utility customers, as determined through ICA, LNBM and competitive sourcing

IOUs' Locational Net Benefit Proposals

SDG&E

	SDG&E Components
1	Energy
8	Environment
2	T&D Losses
3	Generation Capacity
4	Ancillary Services
5	T&D Capacity
7	Distribution Reliability/Resiliency
9	Avoided RPS
10	Avoided Renewable Integration Cost
11	Societal
12	Public Safety

SCE

	SCE Components
1	Energy
8	Avoided Environmental (GHG)
2	T&D Losses
3	RA Capacity
4	Ancillary Services
5	T&D Capacity Expansion Deferral
6	Distribution P.Q. capital and O&M
7	Distribution Reliability & Resiliency capital & O&M
9	Avoided RPS
10	Avoided Renewable Integration Cost
11	Societal
12	Public Safety

PG&E

	PG&E Final Value Components
6a	Generation Energy and GHG
6b	Energy Losses
5a	System or Local Area RA Procurement
5b	Flexible RA Procurement
6c	Ancillary Services
1	Distribution Capacity
4	Transmission Capital and Operating Expenditures
2	Voltage and Power Quality
3	Reliability and Resiliency
6d	RPS Procurement
7	Renewables Integration
8	Societal avoided costs
9	Public safety avoided costs

Keys:
Distribution Transmission Transmission & Distribution Generation

DRP Demo Project B

Locational Net Benefit and Optimal Locations

SDG&E Demo B

Objective

Demonstrate the use of location-specific values based on Commission-approved locational net benefit methodology (LNBM) in comparing conventional projects to DER solutions

Scope

Study only. The demo project will calculate the T&D capacity investment deferral value on two distribution infrastructure projects, one near-term (0-3 year lead time) and one longer-term (3 or more years lead time) within the Escondido and Rancho San Diego areas

Key Deliverables	Estimated Date
• Identify two potential projects for deferral, one near-term and one longer-term • Establish the geographical footprint of where DERs would need to be procured	Q1 2016
• Calculate the investment deferral value for the two projects based on identified grid needs • Identify needed operational characteristics for DER products and services based on identified grid needs • Identify the amount of each service that a DER can provide (e.g. 1 MW of DER provides x MW of reliable peak capacity) • Construct sample DER portfolios that can satisfy characteristics for these services	Q2/3 2016
• Calculate location-specific benefits and costs of the sample DER portfolios • Compare sample portfolios to each other and to the conventional solution being deferred; Demonstrate which would be a least-cost/best-fit solution • Assess any potential DER deployment related timing considerations	Q3 2016
• Report: Provide a report that identifies success measures in evaluating the conventional projects versus alternative DER solutions, including potential timing considerations associated with pursuing and ensuring DERs would be operational within the needed timeframe.	EOY 2016

SCE's Demo B

Objective

Demonstrate the use of location-specific values based on Commission-approved locational net benefit methodology (LNBM) in comparing conventional projects to DER solutions

Scope

Study only. The demo project will calculate the T&D capacity investment deferral value on two distribution infrastructure projects, one near-term (0-3 year lead time) and one longer-term (3 or more years lead time) within the same DPA (most likely area of focus is SCE's Santiago DPA)

Key Deliverables	Estimated Date
• Identify two potential projects for deferral, one near-term and one longer-term • Establish the geographical footprint of where DERs would need to be procured	Q1 2016
• Calculate the investment deferral value for the two projects based on identified grid needs • Identify needed operational characteristics for DER products and services based on identified grid needs • Identify the amount of each service that a DER can provide (e.g. 1 MW of DER provides x MW of reliable peak capacity) • Construct sample DER portfolios that can satisfy characteristics for these services	Q2/3 2016
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PG&E's Demo B

Objective

Demonstrate the use of location-specific values based on Commission-approved locational net benefit methodology (LNBM) in comparing conventional projects to DER solutions

Scope

Study only. The demo project will calculate the T&D capacity investment deferral value on two distribution infrastructure projects, one near-term (0-3 year lead time) and one longer-term (3 or more years lead time) within the same DPA (most likely area of focus is Fresno DPA)

Key Deliverables	Estimated Date
• Identify two potential projects for deferral, one near-term and one longer-term • Establish the geographical footprint of where DERs would need to be procured	Q1 2016
• Calculate the investment deferral value for the two projects based on identified grid needs • Identify needed operational characteristics for DER products and services based on identified grid needs • Identify the amount of each service that a DER can provide (e.g. 1 MW of DER provides x MW of reliable peak capacity) • Construct sample DER portfolios that can satisfy characteristics for these services	Q2/3 2016
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• Report: Provide a report that identifies success measures in evaluating the conventional projects versus alternative DER solutions, including potential timing considerations associated with pursuing and ensuring DERs would be operational within the needed timeframe.	EOY 2016

SDG&E Technical Appendix

1b: Locational Values Replace DERAC System Values

Component	Locational Value
Generation Energy	Generation Energy replaced with LMP
Losses	Distribution loss factors
Generation Capacity	Local Capacity Requirements (LCR) for Resource Adequacy
Ancillary Services	Percentage of generation energy value
T&D Capacity	Avoided Sub-Transmission, Substation and Feeder Capital and Operating Expenditures Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures Avoided Transmission Capital and Operating Expenditures
Environment	Qualitatively describe the Societal Avoided Costs by using the CalEnviro Screening tool
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource

1b: Benefits Analysis

- SDG&E will compare the net cost of the DER solution to the cost of the traditional upgrade to determine the cost effective solution
  - **$DER Benefit** = Cap_{cost}$ +$O&M$_{cost}$- $NetDER$_{cost}$ - $DER integration$_{cost}$

– The DER project will need to realize additional value, such as contributing to resource adequacy requirements, avoided RPS, and environmental and societal benefits through appropriate processes

SCE Technical Appendix

1b. Optimal Location Benefit Analysis

- SCE's objective is to identify optimal locations, likely in form of heat maps, where DERs could provide a high benefit value
- SCE's locational net benefits methodology (LNBM) identifies DER benefit components and describes how to quantify them
- List of benefit components for LNBM is based on E3's Distributed Energy Resources Avoided Cost (DERAC) calculator
  - For the LNBM, system-level values in the DERAC are replaced with location-specific values
  - Additional components were added based on the Final Guidance to the list from DERAC

Identifying Optimal Locations and Maintaining Ongoing Updates

- SCE will conduct an indicative analysis using high value benefit components (e.g., distribution deferrals or energy value) to identify locations where DERs are likely to provide the most benefits
  - Such location areas may span multiple circuits or substations
- Locations would be categorized or ranked based on the relative benefits that DERs are likely to provide
  - SCE would publish a list of these optimal locations, potentially in the form of "heat maps"
  - SCE plans to update this list after the conclusion of its annual internal distribution planning process

Distribution Planning Review Group (DPRG)

- SCE is recommending that a distribution deferral framework should be developed in this proceeding, to establish upfront standards and criteria to determine which traditional grid investments would be considered for potential deferral
- SCE also recommends establishing a Distribution Planning Review Group (DPRG) process to review how SCE applies this framework and to promote transparency
    - DPRG would be comprised of eligible non-market participant parties who sign non-disclosure agreements
    - In general, this process would work similar to the Procurement Review Group (PRG) process to review utilities' procurement activities in the wholesale energy markets

Demo B

B - Optimal Location Benefit Methodology

Objective

- Demonstrate the Commission-approved locational net benefit methodology (LNBM) approach

Approach

- Use the LNBM to calculate the distribution capacity investment deferral on two distribution infrastructure projects:
    a. One near-term project (<3 years)
    b. One longer-term project (>3 years)

Project Location

- To be determined

Timing

- Commence no later than one month after Commission approval
- Submit final report by Q1, 2017

PG&E Technical Appendix

Chapter 2.c. Optimal Location Benefit Analysis:

Locational Benefits and Costs Methodology

Locational Benefits and Costs Methodology

- Purpose of optimal location benefits/costs analysis is to:
  - Identify locations where DERs have lowest cost impact and benefit the grid
  - Enable PG&E to make better distribution investment decisions for our customers
- General approach
  - Use locational marginal costs or benefits (avoided costs) to select optimal locations
  - Major cost/benefit categories
    - **Distribution**
    - **Transmission**
    - **Generation**
    - **Other Societal, Safety**

Guidance on Locational Value Components

Start with DERAC*, add new and more granular components

	DERAC Components
1	Energy
2	Losses
3	Generation Capacity
4	Ancillary Services
5	T&D Capacity
6	Environment
7	Avoided RPS

+

	New /More Granular Components
1	Distribution Capacity
2	Voltage and Power Quality
3	Reliability and Resiliency
4	Transmission Capital and Operating Expenditures
5	Flexible Resource Adequacy (RA) Procurement
6	RPS Integration
7	Societal avoided costs
8	Public safety avoided costs

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	PG&E Final Value Components
1	Distribution Capacity
2	Voltage and Power Quality
3	Reliability and Resiliency
4	Transmission Capital and Operating Expenditures
5a	System or Local Area RA Procurement
5b	Flexible RA Procurement
6a	Generation Energy and GHG
6b	Energy Losses
6c	Ancillary Services
6d	RPS Procurement
7	Renewables Integration
8	Societal avoided costs
9	Public safety avoided costs

Keys:
Distribution Transmission Transmission & Distribution Generation

* E3's Distributed Energy Resources Avoided Cost Calculator (DERAC) provides system-wide avoided costs.

Structure of PG&E's Methodology Descriptions for each Component

Value Component Name:

Value Component Definition:

Determining DERs' Impact:

How to quantify a DER's impact (decrease / increase) on the need for this value component

Translating DER Impact Into Avoided or Increased Cost:

How to translate an increased or decreased need for this value component into monetary terms

Granularity of Locational Variation:

How location-specific does PG&E expect this component to be

Example: Components 1-3 (Distribution)

Value Component Definition: Avoided or increased cost due to DER for:

1. Distribution capacity
2. Voltage and power quality
3. Reliability and resiliency (respond to routine and major outages)

Determining DERs' Impact: Distribution engineering tools used to determine

- "Right Time" - Identified deficiency requiring investments exists
- "Right Availability" - Coincidence of deficiency and DER hourly output
- "Right Location" - DER is connected at the correct locations
- "Right Size" - DER can assure necessary size to meet need

Translating DER Impact Into Avoided or Increased Cost:

- Present value of investment deferral (or acceleration) due to DER

Granularity of Locational Variation:

- Anticipated to vary from feeder to feeder within PG&E service territory

Example: Components 1-3 (Distribution)

Value Component Definition: Avoided or increased cost due to DER for:

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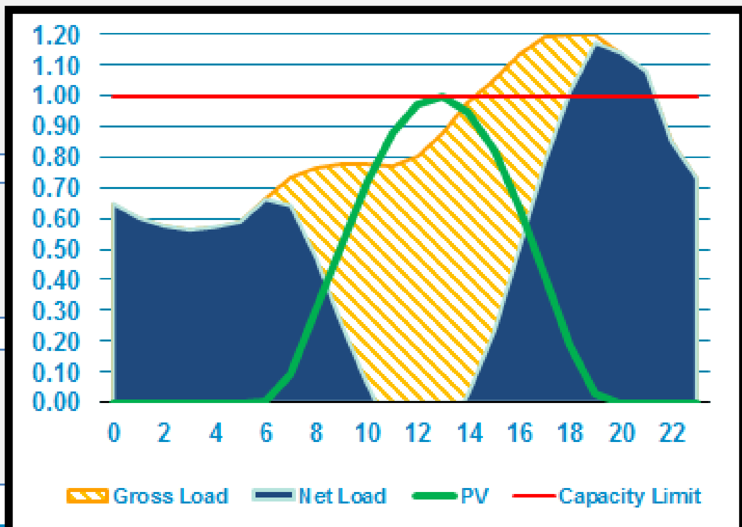

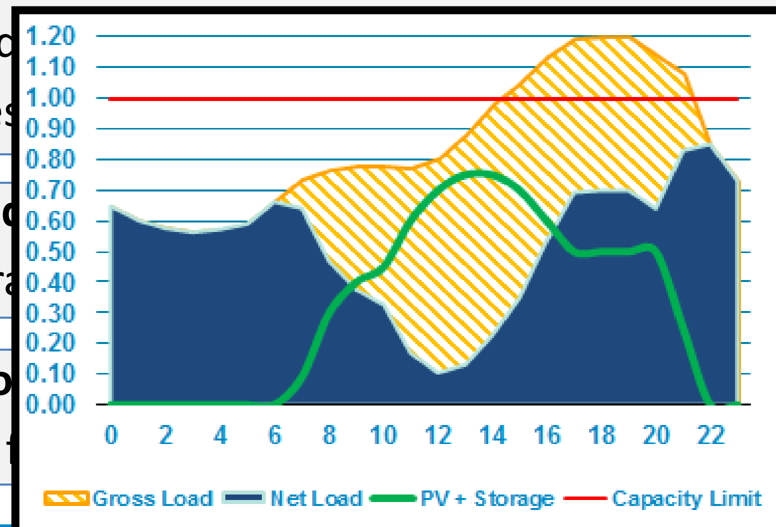

Example: 5.a. System or Local RA

Value Component Definition: Avoided or increased Resource Adequacy (RA) capacity procurement to meet annual system or local RA requirements

Determining DERs' Impact:

- Determine whether DER's impact is already accounted for in RA requirements
- Develop DER's hourly profile or, if appropriate, dispatch parameters
- Use Equivalent Load Carrying Capability (ELCC) analysis to determine DER's RA value

Translating DER Impact Into Avoided or Increased Cost:

- Present value of investment deferral (or acceleration) due to DER
- Proprietary System and Local RA Price forecasts based on net cost of marginal capacity additions

Granularity of Locational Variation:

- Anticipated to vary from Local Capacity Requirement (LCR) Area to LCR Area

IOUs' Value Components Are Aligned

- The three IOUs follow the same approach
  - Start with the same E3 avoided cost components in DERAC
  - Add new and more granular CPUC-prescribed components
  - Produce a larger, more granular set of value components
  - Propose a location-specific methodology for each value component
- As requested in CPUC Guidance Ruling, the IOUs cover the same costs and values.
- Slight variations in naming and grouping of value components and use of certain tools
- DRPs suggest the IOUs will consider whether DERs' net cost is higher or lower than the net cost of distribution investment projects using a locational net benefits approach
- Locational net benefits methodologies need to be coordinated across a variety of DER-related proceedings and system planning processes